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Are we there yet? Improving solar PV economics and power planning in developing countries: The case of Kenya

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ABSTRACT

Despite the rapid decline in the cost of solar photovoltaic (PV) systems in the past five years, even recent academic research suggests that the cost of generating PV electricity remains too high for PV to make a meaningful contribution to the generation of grid electricity in developing countries. This assessment is reflected in the views of policymakers throughout Africa, who often consider PV as a technology suited only to remote locations and small-scale applications. This paper therefore analyzes whether, in contrast to conventional wisdom, PV is already competitive with other generation technologies. Analytically, the paper is based on a levelized cost of electricity (LCOE) model to calculate the cost of PV electricity in Kenya, which serves as a case study. Based on actual technology costs and Kenya's solar resource, the LCOE from PV is estimated at USD 0.21/kWh for the year 2011, with scenario results ranging from USD 0.17–0.30/kWh. This suggests that the LCOE of grid-connected PV systems may already be below that of the most expensive conventional power plants, i.e. medium-speed diesel generators and gas turbines, which account for a large share of Kenya's current power mix. This finding implies that researchers and policymakers may be mistaken in perceiving solar PV as a costly niche technology, rather than a feasible option for the expansion of power generation in developing countries.

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1. Introduction

Developing country governments throughout Africa face numerous challenges in the development of their power sectors. First, upgrading and expanding generation capacities and electricity grids are of primary concern in order to keep up with demand increases and to sustain economic growth. Second, providing grid-electrification or alternative off-grid solutions to those 69% of the population in sub-Saharan Africa currently lacking access to the electricity grid ([1]). Third, undertaking the necessary investments (recently estimated at USD 160–215 billion over a 10-year period by Rosnes and Vennemo [2]) and tackling possible capital constraints, skills shortages and lack of governance capacity that can prevent countries from developing their power sectors as fast or as efficiently as necessary [3]. Moreover, African governments need to decide which energy resources to exploit for power generation, and the decision on the appropriate resources is no trivial task. It involves trade-offs between economic costs (and hence affordability to consumers), security and reliability of supply, environmental concerns (both nationally, and, in the form of greenhouse gases, internationally) and social aspects, such as local employment (e.g. [4]). In pursuing these different policy goals, African governments have traditionally relied on fossil fuel technologies (predominantly oil and gas) and large-scale hydropower, which has for a long time been the workhorse of sub-Saharan Africa's power sector [5].

Only in more recent years have countries in the region started to consider other alternative power generation technologies from nuclear power to a range of renewable energy technologies, such as biomass, wind, geothermal and solar energy. For instance, several large-scale wind and geothermal energy projects have already been realized in a number of African countries from the Sahel to the Cape of Good Hope [6], and governments and energy planners generally seem to accept that these two resources can constitute viable energy supply options. Other renewable energy technologies, on the other hand, are usually not yet considered economically feasible and are therefore confined to small-scale off-grid electricity generation. Solar energy is probably the most prominent example of such a renewable resource that, while offering huge technical potential, is perceived as economically unattractive for contributing to power generation on any significant scale by most experts and policymakers (e.g. [3]). Thus, after years of academic and political debate, there appears to be almost a consensus that the use of solar energy technologies should be confined to the electrification of households, villages, health-centers etc. far from the centralized grid, where these technologies already offer high economic returns [2].

However, recent rapid declines in the costs of solar energy technologies, especially solar photovoltaic (PV), give rise to the question whether the economic potential of these technologies for large-scale power generation is actually under-appreciated both by academic researchers and by decision-makers in African countries. Between 2008 and 2009 alone, prices for solar PV modules – which are the most important component of solar PV systems – decreased by some 50%, suggesting that the economics of using solar power have improved substantially in the past few years. However, much of the analysis on future power generation globally and in sub-Saharan Africa carried out by academic researchers relies on technology cost-assumptions that are 5–10 years old and thus outdated [7]. When technological change and market dynamics change as rapidly as in the case of solar energy technologies, using outdated data (even if it is only a few years old) will almost certainly lead to flawed research outcomes. Where policymakers rely on the fruits of academic research to support their decision-making, results flawed in such a way can give rise to misperceptions that may, ultimately, lead to policymakers reaching decisions that do not appropriately reflect the latest developments and thus may move the energy sector away from the economic optimum.

In this paper, it will therefore be investigated and analyzed whether misperceptions among energy planners stemming from the use of outdated data in academic research on solar energy technologies do indeed lead to an under-appreciation regarding the potential of these technologies for the generation of grid-electricity. This analysis will be done with reference to the case of Kenya, a low-income developing country in East Africa that is already one of the biggest markets for solar home systems and other off-grid solar systems for rural electrification [8]. Whereas energy planners and policymakers in Kenya promote these off-grid uses of solar energy, solar power generation on a larger scale is currently not considered economical and hence excluded from national power planning. Hence, this paper aims to shed light on the question whether this is still a justified position, given the recent improvements in the global cost of solar energy technologies, by estimating current and near-term levelized costs of electricity (LCOE) from solar PV in Kenya and by contrasting these with LCOE estimates for competing power sources.

The remainder of this paper is structured as follows. Section 2 provides the necessary background to the present study by drawing on the relevant literature on the potential and cost of solar electricity generation on a global, regional and national level. Section 3 introduces the conceptual framework and the methodology employed, while Section 4 provides information on Kenya's power sector and its use of solar energy. Section 5 presents the main results, as well as a comparison with the existing literature. Section 6 concludes with a discussion of the results and their policy implications.

2. Background

This section presents the results of recent research into the potential role of solar energy technologies for power generation, both on a global scale and more specifically in sub-Saharan Africa. Furthermore, it provides readers with information on findings from the most up-to-date academic and grey literature regarding the cost of electricity generation from solar PV systems, both globally and in specific regions and countries.

2.1. *Potential role of solar energy in electricity generation*

There is wide divergence in the assumed or expected role of solar energy technologies in the future supply of electricity. The Intergovernmental Panel on Climate Change's (IPCC) 2011 special report on renewable energy sources and climate change mitigation notes the very large variance of potential deployment scenarios, with electricity generation from solar energy ranging from marginal to it becoming one of the major sources of energy supply on a par with bioenergy and wind energy by 2050, depending on the modeling assumptions [10]. Likewise, the International Energy Agency's (IEA) latest World Energy Outlook contains wide variation between the different policy scenarios (see Table 1), which in the case of Africa results in the expected solar PV capacity in 2035 diverging by more than a factor of two (International Energy Agency and Organisation for Economic Co-operation and Development [1]). Similarly, the Global Energy Assessment (GEA), led by researchers at the International Institute for Applied Systems Analysis (IIASA), produces a wide range of expected outcomes regarding the share of solar energy technologies in the primary energy mix; with solar generally expected to contribute from 10 to 20% by 2050 depending on the pathway scenario. Moreover, in line with predictions from the IPCC and IEA, the GEA study also foresees only a limited contribution of solar energy technologies prior to circa 2025 [11].

Table 1
IEA scenarios for solar energy deployment in 2035 worldwide and in Africa (share in total capacity/generation in parentheses; CPS is the ‘current policies scenario’, NPS is the ‘new policies scenario’ and 450 is the ‘450 ppm scenario’) (table based on [1]).

Year	2009		2035					
Scenario	Base year		CPS		NPS		450	
	World	Africa	World	Africa	World	Africa	World	Africa
Solar PV (GW)	22 (0%)	0 (0%)	314 (3%)	16 (5%)	499 (6%)	21 (7%)	901 (10%)	34 (9%)
Solar PV (TWh)	20 (0%)	0 (0%)	435 (1%)	27 (2%)	741 (2%)	38 (3%)	1332 (4%)	61 (5%)

Table 2
Solar energy levelized cost assumptions and expected contribution of solar energy for power generation (table based on sources cited in column (1). NB: IEA and OECD [1] show the average subsidy, not the levelized cost, which must exceed the subsidy shown here.

Report/study	Geographic focus	Reported LCOE (USD/kWh)	Year of cost estimate; source	Contribution of solar energy
Edenhofer et al. [10]	World	0.074–0.92	Various years (in USD_{2005}); various sources	On-grid & off-grid
IEA and OECD [1]	World	0.425 (average subsidy)	2010; own data	On-grid & off-grid
Deichmann et al. [4]	Ethiopia, Ghana, Kenya	0.55–1.216	2008; KMOE [14]	Only off-grid
Johansson et al. [11]	World	0.15–0.70	2009 (in USD_{2005}); n.a.	On-grid & off-grid
Hamilton and Stöver [12]	World	0.226–2.031 (average: 1.018)	2005, 2008 (in USD_{2007}); OECD [15] and EC [16]	Only on-grid
Collier and Venables [3]	Africa	0.411–0.617	2010 (in USD_{2008}); IEA/NEA [9]	Mostly off-grid
Rosnes and Vennemo [2,13]	Sub-Saharan Africa	n/a	2009; various sources	Only off-grid

It is a widely accepted fact that the amount of solar energy that reaches the earth every day would be sufficient to cover all the world's primary energy needs from a technical perspective. However, the studies cited above (as well as many others) point out that relying primarily on solar energy technologies for climate change mitigation at this point in time could be a very expensive undertaking. For example, Hamilton and Stöver [12] estimate that the cost of switching from fossil fuel-based power generation to solar energy technologies would require a CO_2 price of USD 1174–2096/tCO_2 for solar PV to become competitive, which would make solar PV by far the most expensive mitigation option within the field of power generation. While one might criticize that they use outdated solar cost assumptions, as the authors also concede in their paper, the current consensus view among researchers generally appears to be that solar energy technologies are not yet economically viable, as their cost of power generation is generally too high compared to most other centralized electricity generation technologies.

In the specific case of Africa, a number of recent papers look into the potential contribution of solar energy for the electrification of the continent. In keeping with the general consensus, Collier and Venables [3] also argue that the potential role of solar energy is strictly limited to off-grid electrification and, referring to Deichmann et al. [4], that solar PV will not cover more than 10% of off-grid households in the foreseeable future. The authors base their opinion on the high cost of the technology, but also point towards some additional factors that are preventing Africa from using its abundant solar and hydro resources, namely shortages of capital, skills and governance capacity. In order to “green Africa”, they urge international action that addresses these factor scarcities and that would enable the continent to exploit its green energy rather than its hydro-carbon resources. Taking a more detailed look at the matter of providing electricity to Africa, Rosnes and Vennemo [2] produce estimates for the investment cost of providing electricity to sub-Saharan Africa over a 10-year period (c.f. Section 1). Their model contains a number of technologies (hydropower, coal, natural gas, diesel and heavy fuel oil, nuclear and geothermal) available for power generation, while mini-hydro and solar PV are only considered as off-grid technologies in rural areas [17]. The fact that solar is only considered as an option for off-grid electrification by the authors results from their assumed high investment costs for solar energy technologies (ranging from USD 10 to 22/Wp for a 50 Wp solar home system), thus rendering solar PV economically unattractive for large-scale electricity generation [13]. Looking specifically at the economics of renewable energy sources for rural areas in sub-Saharan Africa, Deichmann et al. [4] likewise argue that solar PV will become increasingly economic for rural electrification, but that centralized power generation will also have to be decarbonized as it expands in Africa. The authors base the latter argument on their finding that centralized electrification will continue to be more efficient for the majority of households, for whom renewable energy sources will continue to be more expensive than grid extension.

In summary, the various studies cited above find that solar PV and other solar energy technologies are generally expected to contribute an increasing share to electricity generation in the coming decades. However, their contribution will probably be constrained by their high current costs, which render them uncompetitive without subsidies. Therefore, all studies reviewed above expect that the role of solar PV in Africa will remain mostly limited to off-grid electrification for years to come. Table 2 provides an overview of present levelized cost assumptions used by the papers reviewed above, as well as the expected or assumed role of solar PV in the energy sector.

2.2. Solar electricity generation costs

As noted in the previous section, expectations and assumptions on the future role of solar PV diverge widely. While this can to some extent be explained by differences in the geographic focus of the various studies, a second factor behind the wide range are the specific technology assumptions explicitly or implicitly made in the studies. That is, whereas some of the literature looks at a variety of different applications of solar energy technologies (e.g. [10]), others analyze solar PV only in the context of small-scale off-grid applications (e.g. [4]). While researchers should be very careful to use appropriate cost estimates, this is not always the case, as exemplified by Rosnes and Vennemo [2], who use solar off-grid costs for on-grid applications as well [13].

In addition to differences in the levelized costs of solar technologies being explained by geographic and type-of-use assumptions,

the above sample of studies reveals another major determinant for the proper investigation of the potential and limits of the solar resource exploitation: the use of recent and reliable data regarding the cost and efficiency of the various technologies. In this respect, readers should note that some of the studies cited earlier rely on data that are quite old (as acknowledged, e.g. by [12]). This section therefore continues with a presentation of the most recent, i.e. those from the years 2010 to 2012, cost estimates and technical parameters for solar PV.

The International Energy Agency (IEA)/Nuclear Energy Agency's (NEA) 2010 report on the projected costs of generating electricity [9] provides a comprehensive overview of generation costs for a wide range of technologies and across a large number of countries. While the report does not contain information on electricity generation costs in any African country but South Africa, the data collected in 21 countries make it a useful starting point for the analysis of the likely cost of solar electricity even in sub-Saharan Africa (e.g. [3]). For solar PV the report shows an LCOE of USD_{2008}/kWh 0.411 for a 5% discount rate and 0.617 for a 10% discount rate, making the technology by far the most expensive electricity generation option in the study.

Several other papers published in 2011 and 2012 largely confirm the overall view regarding solar energy technologies expressed in IEA/NEA [9]. For example, Timilsina et al. [18] base their own analysis on the IEA/NEA report in order to derive estimates for the minimum and maximum LCOE from solar PV projects. Not surprisingly, they also find that solar energy technologies are generally not yet competitive with mainstream technologies (and even wind energy), a view that is confirmed by Peters et al. [19]. These use a different set of studies for their cost and performance assumptions, yet they also find that solar technologies will reach competitiveness with conventional forms of power generation only around 2020 in the countries they analyze (Spain, Germany, China, Egypt and the United States).

As the costs of solar energy technologies, and most importantly solar PV, decline rapidly, researchers and analysts following developments in the global solar energy market closely have started to argue that academic research relying on data that is just a few years old can already lead to an 'under-appreciation' of the technologies' true economics (e.g. [20]). This matter is further explored by Bazilian et al. [7], who argue that decision-makers especially in developing countries have not yet taken note of the rapid decreases in PV costs and thus continue to consider solar PV as uncompetitive vis-à-vis other electricity generation technologies, whereas it could already be competitive depending on the specific circumstances and the concrete metric used for the measurement of 'competitiveness'. The authors point out that the cost of solar PV has seen steady declines of about 15 to 24% for every doubling of cumulative module sales, and that solar PV module prices have dropped especially rapidly since late 2008. Whereas the cost of solar PV modules stayed flat at around USD 3.5–4.0 per Watt peak (Wp) between 2004 and late 2008, prices for modules had fallen to as little as USD 0.85–1.01/Wp by April 2012 [7] and the widely followed Solarbuzz module price index reached USD 2.29/Wp in March 2012, a decline of about 50% since late 2008 (c.f. [21]).

Although solar power systems do not consist of solar modules alone, Bazilian et al. report that the LCOE for solar PV has equally declined by up to 50% since 2009 to as little as USD_{2012}/kWh 0.16 for PV systems based on thin-film technology [7]. This value compares well to Solarbuzz's estimate of USD_{2012}/kWh 0.15 for a 500 kWp industrial solar system installed in sunny locations [22]. Other recent studies and reports estimated the global cost of solar electricity in a broad range of ca. USD/kWh 0.10 to 0.50 for solar PV, depending on site-specific assumptions, installed capacity, solar technology employed, the date of publication, and numerous other factors [23,24,25,26].

Only very little academic and non-academic research specifically looks at the cost of generating solar electricity in East Africa or even sub-Saharan Africa more generally in recent years. Among these, a report by Hauff et al. [27] estimates the cost of solar PV electricity in Kenya at USD_{2010}/kWh 0.163–0.175, other studies report a range from USD_{2010}/kWh 0.24 to 0.37 for solar PV “in good African conditions” ([28], p. 21) and specific estimates of USD_{2010}/kWh 0.271 [29] and USD_{2012}/kWh 0.2749 [30] for good sites in Kenya.

The wide range of estimates for the cost of solar electricity both on a global scale and in Africa presented in the preceding section leads to the question how much it would actually cost to generate electricity from solar energy technologies in a country such as Kenya. For, as Bazilian et al. [7] stress in their paper, the LCOE varies widely based on geography and the financial return required from investors in a specific project. The authors continue by pointing out that deriving the LCOE “requires an estimate of long-term PV system performance—a very context-specific outcome driven by factors including solar insolation at the site, component technologies and specifications, overall system design and installation, and maintenance” ([7], p. 332).

This paper will therefore continue with an assessment of the cost of solar electricity generation in Kenya, where policymakers currently consider the cost of solar energy as far 'too high' for large-scale power generation. As such, this paper complements two of the studies cited previously (i.e. [27,29]), which also calculate the cost of solar PV in Kenya, but whose two main shortcomings are that they do so on the basis of global rather than local technology costs and on the basis of costs from 2010 or earlier.

3. Methodology

3.1. Conceptual framework

In analyzing the cost of solar electricity in Kenya, this paper draws on the requirements for economic efficiency. In the context of electricity markets, efficiency requires that the marginal benefit of some given activity should be equal to the marginal cost of that activity. With respect to the use of electricity this principle would require that the marginal social benefit attributed to the consumption of, say, one kilowatt-hour of electricity should be exactly offset by the marginal social cost of generating this kWh to ensure economic efficiency. In an unregulated market this will typically not be the case. Furthermore, policymakers might also be concerned with the allocation of electricity generation among various technologies, such as fossil fuels and renewable energy sources, in order to ensure energy security or to achieve environmental aims, for instance. In this respect, economic efficiency would require that the marginal social cost of producing electricity would be equalized across all available generation technologies ('equimarginal principle'). The equimarginal principle implies that economic efficiency is maintained by ensuring that a given quantity of electricity cannot be produced at a lower cost by switching from one (higher cost) technology to another (lower cost) technology.

Building upon this important principle, wholesale electricity markets in advanced economies are typically designed such that the marginal power source sets the overall market price at any point in time. In order to do so, a merit order of generation sources, which orders the different power plants by their generation costs, is constantly established, with the generation cost of the last power plant required to fulfill demand determining the price at which the wholesale market clears (c.f. [9] for further information on electricity market design).

However, the merit order plays a role in long-term energy planning only in the sense that such a merit order (which is, essentially, a marginal cost curve for electricity generation) also appears when generation technologies are ranked according to their long-term generation costs/long-run marginal costs. Least-cost power planning, which is a widespread approach to energy planning in developing countries, builds upon these principles and is usually conceptualized in the form of comparisons of the LCOE for different generation options. Social planners then aim to ascertain economic efficiency by selecting those energy sources with the lowest LCOE for power sector expansion. In line with much of the literature, and as this is also the approach taken by Kenyan energy planners, this paper will continue with an analysis of the LCOE of solar energy technologies in Kenya.

3.2. Levelized cost of electricity model

This section briefly introduces the rationale and methodology of determining the levelized cost of electricity, as this method is being used widely for the purpose of electricity-generation technology comparisons. It is the approach taken by the studies presented in Section 2.2 and also the methodology used by Kenyan energy planners for the determination of 'candidate sources' for the country's Least Cost Power Development Plan (see Section 4.3). The LCOE methodology is not without its critics, as it also has severe methodological shortcomings, e.g. in the economic valuation of intermittent resources. Bazilian et al. [7] and Schmidt et al. [29], among others, elaborate on some of the limitations of this approach, but maintain that it is still superior to other approaches, such as a strict comparison of the capacity cost (e.g. USD per watt or Wp) or the somewhat imprecise metric of 'grid parity'.

In contrast, the LCOE is a common metric for the comparison of electricity generation technologies. It allows comparing different technologies on the basis of what it costs to generate one unit of electricity by dividing all costs incurred throughout a project's lifetime by the total amount of electricity generated during that lifetime. Thus, the LCOE concept goes back to the economic principles outlined above, enabling energy planners and policy-makers to compare generation costs of conventional and renewable resources. Eq. (1) describes the LCOE model developed and used for the calculation of the cost of solar electricity in Kenya. All variables needed for the LCOE calculation can be identified in this equation. Further information on the LCOE model, its derivation and economic foundation can be found in Appendix 1, while the specific variable values used for the LCOE calculation are presented in Section 5.1.

$$\mathrm{LCOE} = P_{\mathrm{elec}} = \frac{\sum_{t=0}^{T} (I_t + O_t + D_t)/(1+r)^t}{\sum_{t=0}^{T} S_{t=0}(1-d)^t/(1+r)^t} \quad (1)$$

where, LCOE is the levelized cost of electricity per unit in period t, P_{elec} is the minimum electricity price required to break even, T is the economic life of the project, t is the year of operation (0, 1, 2,… n), where $t=0$ is the year of installation and start of operation, I_t denotes the initial investment, O_t stands for operation and maintenance costs, D_t are the decommissioning costs, r is the discount rate, $S_{t=0}$ stands for the rated energy output in period $t=0$, and d is the annual module degradation factor.

In order to determine the LCOE of solar electricity in Kenya, information on the economic life of the project (T), the initial investment (I_t), on-going operation and maintenance costs (O_t), and decommissioning costs (D_t) is required. Furthermore, information on the expected electricity yield ($S_{t=0}$) as well as module decay (d) is necessary. In order to discount both annual costs and annual electricity generated, an appropriate discount rate (r) is also needed.

4. Kenya case study

The East African country of Kenya is a prime example of an economy facing what some experts call the 'African energy challenge' [10,28,31] most acutely: It has a quickly growing population and rising prosperity that both lead to increasing energy demand. Yet, to date Kenya's electrification rate is among the lowest in the world, with only 14% of the overall population connected to the grid in 2005 [32]. At the same time, Kenya continues to rely heavily on traditional biomass for most of its primary energy needs, while undergoing structural changes in a power sector that used to be dominated by clean and abundant hydro power as the primary source of electricity. The country therefore serves as a good example for emerging economies that face the energy challenge and where solar energy, already used since the 1970s, might be part of the solution.

Situated along the equator, Kenya is among the 'Sunbelt' countries identified by Hauff et al. [27] which are located between the latitudes of 35°N and 35°S. Of the 66 countries analyzed by the authors, Kenya ranked 14th based on its installed solar PV capacity in 2009 (2010: 19th), as estimated by Werner et al. [33]. Ranking Sunbelt countries by solar PV's share in overall electricity generation capacities yields somewhat different results, with Kenya attaining 8th rank among Sunbelt countries in 2010. With its estimated 16 MWp of solar capacity installed mostly in off-grid systems [34], one could expect that Kenya might be ideally placed to exploit its solar resource also for the large-scale power generation that is the focus of this paper. Furthermore, regulation of its energy market and long-term energy planning are relatively transparent and explicit, which allows an analysis of how academic research enters the policy domain.

4.1. Current power infrastructure

The electricity sector of Kenya is currently dominated by large-scale hydropower, thermal power plants and geothermal energy. By the end of 2011, the total installed electricity generation capacity was 1589.6 MW. Table 3 shows the shares of different technologies in more detail.

Over the period 2006 to 2011, Kenya's reliance on fossil fuels increased further, with additions of some 224 MW of new thermal capacity. This capacity was installed in heavy fuel oil (HFO)-fired medium-speed diesel plants that were contracted from independent power producers (IPP) to supply emergency power in times of shortfalls in hydropower generation. Furthermore, approximately 100 MW of large-scale hydro, 70 MW of geothermal, 24 MW of biomass, and 3.7 MW of wind power as well as 0.6 MW of solar PV were added to the grid [34]. As of July 2011, another 887 MW were 'under implementation', most of it also in medium speed diesels (MSD, 252 MW), various projects of Kenya Generating Company (KENGEN, 280 MW) and the 300 MW Lake Turkana wind project [35].

Table 3
Electricity generation capacity and generation in Kenya in 2011 [34].

Technology/source	Capacity (MW)	Capacity share (%)	Generation (GWh)	Generation share (%)
Large hydro (> 10 MW)	763.3	48	3427*	47
Thermal	582.6	37	2242	31
Geothermal	198	12	1453	20
Other (biomass, small hydro, wind, solar PV)	45.7	3	105	1
Total	1589.6	100	7227	100**

* Figure for generation from large hydro includes small hydro.
** Numbers do not add to 100% due to rounding.

Kenya's electricity sector can be described as partly liberalized, with about 75% of generation capacity in the hands of the partially state-owned entity KENGEN. The remaining generation capacity is owned and operated by a number of IPPs that, like KENGEN, sell their electricity on the basis of long-term off-take agreements to Kenya Power and Lighting Company (KPLC), which is also partly state-owned. Currently, KPLC is the sole distribution company in Kenya, while all transmission is within the remit of Kenya Electricity Transmission Company (KETRACO), a fully state-owned entity. The power sector is regulated by the Energy Regulatory Commission (ERC), which is operationally independent from the Ministry of Energy, or MoE [36].

4.2. Solar energy in Kenya

The daily solar irradiation across Kenya is reported to average 4–6 kWh/m², but its overall solar resource is generally not well understood. The Solar and Wind Energy Resource Assessment (SWERA) project undertook the sole comprehensive effort to date to study the country-wide availability of wind and solar energy. It concluded that across the country "the total area capable of delivering [direct normal irradiance of] 6.0 kW[h]/m^2 per day is about 106,000 square kilometers whose potential is 638,790 TWh [for solar heat and electricity generation]" ([37], p. 28). Thus, solar energy alone could theoretically contribute almost 100 times as much energy as Kenya currently consumes in electricity (see Appendix 2 for further details).

Despite the availability of a technically useful solar energy resource, Kenya's solar market remains relatively undeveloped when compared to other countries, such as Germany, Spain, China and the US. By 2010 there were approximately 8–10 MWp of installed solar capacity, of which the vast majority was installed in solar home systems (SHS) of approximately 20–50 Wp each. My own research suggests that at least 320,000 such SHS are in use throughout the country, mostly providing electricity to households not connected to the grid. The remaining 2 MWp were mostly installed in other off-grid systems for schools, health centers etc. [38]. More recently it was estimated that the total installed capacity in small off-grid solar systems could have reached 16 MWp by July 2012, with an additional 0.575 MWp installed in two larger on-grid systems: A 515 kWp project at the United Nations compound in Nairobi and a 60 kWp system at the SOS Children's Home in Mombasa. Being grid-connected, both systems serve to familiarize Kenya's grid operators with solar PV as a large-scale power generation technology [34].

4.3. Energy policy and planning

The Energy Regulatory Commission prepares a bi-annual Least Cost Power Development Plan (LCPDP) to guide power sector development (see Appendix 3 for further details on energy planning in Kenya). The latest version of the LCPDP, released in March 2011, covers the 20-year period from 2011 to 2031 [36]. Methodologically, the report utilizes a least-cost planning approach aimed at delivering the required level of electricity supply at any given point in time at the least overall economic cost. The LCPDP is driven by a load forecast that sees electricity demand increase about tenfold during the 20-year planning period (reference scenario). Electricity demand in the base year 2010 was put at 6683 GWh and forecast to rise to 61,490 GWh by 2031, an annual increase of about 12%. This forecast demand translates to a peak load in the reference scenario of 10,612 MW by 2031, a nearly tenfold increase compared to the year 2010 (1120 MW).

Upon screening a large number of potential generation technologies, the LCPDP establishes a ranking of base load and peak load sources based on their expected LCOE. Assuming an 8% discount rate, geothermal, wind and hydropower emerge as the cheapest base load technologies, while gas turbines and MSDs are the only peak load sources considered (see Table 4 for more details). Based upon this ranking of different technologies, the LCPDP produces a 'least cost' power expansion plan in order to meet peak demand (plus reserve margin) in all years studied by the report. Fig. 1 shows planned capacity expansion by technology and by year.

Two important observations can be made when looking at Kenyan plans for power generation expansion in the next two decades. First, while emphasizing low-carbon technologies (particularly geothermal and nuclear, followed by wind and hydro) in the long-run, much of the immediate capacity expansion until 2015 is expected to occur in MSD power stations. These are expected to more than double in capacity between 2010 and 2013, bringing their share in overall installed capacity to 35% in 2013 before decreasing again as geothermal and wind power expand from 2013 on (see Fig. 2). This reliance on MSD is in line with the trend observed since 2008 (see Section 4.1) and further reflects the projects already committed for realization in 2012–2016 [39]. The observation that MSD are likely to dominate capacity expansion in the short-term is very significant as, in line with the UNFCCC's 'build margin' approach, MSD and their associated high costs and carbon emissions would feature very prominently in determining Kenya's baseline power mix for climate mitigation [29].

Table 4
Candidate power projects according to LCPDP 2011. LCOE were calculated with an 8% discount rate. Further details on technology assumptions can be found in [36].

Candidate power plant	Load factor (%)	LCOE (USct$_{2010}$/kWh)
A. Ranking of base load projects:		
1. Geothermal	93	6.9
2. Wind	40	9.1
3. Low Grand Falls (hydro)	60	9.3
4. Nuclear	85	10.2
5. Mutonga (hydro)	60	11.1
6. Gas Turbine (natural gas)	55	11.3
7. Coal	73	12.7
Imports from Ethiopia	70	6.5
B. Ranking of peak load projects:		
1. Gas Turbine (natural gas)	20	15.1
2. Medium Speed Diesel	28	21.7
3. Gas Turbine (kerosene)	20	30.2

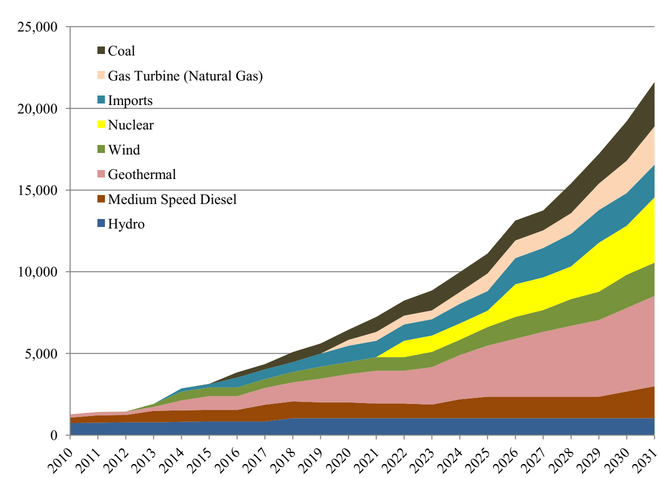

Fig. 1. Total installed electricity generation capacity in GW by technology (includes imports of hydro-electricity from Ethiopia) according to LCPDP 2011–2031 ("base case").
Source: Author's calculation based on [36].

The second observation regards the role of solar power in the LCPDP. As can be seen in Figs. 1 and 2, solar energy technologies are not expected to contribute to Kenya's electricity supply in any way between 2011 and 2031, a view reconfirmed by the Medium Term Plan 2012–2016 (c.f. [39]). Indeed, while the LCPDP stresses the "great potential for the use of solar energy throughout the year because of [the country's] strategic location near the equator" ([36], p. 56), the only applications for solar energy appear to be SHS, solar water heating and other off-grid uses in rural areas far from the grid. The background to this view seem to be two studies reviewed for the LCPDP, namely the IEA/NEA's 2005 report on the projected costs of generating electricity [15] and the Energy Information Administration's Annual Energy Outlook 2005 [40]. These produced LCOE estimates for solar PV ranging from USD_{2003} 0.121 to 0.222 (at a 5% discount rate).

The LCPDP does not state clearly why solar power technologies were not considered among the candidate sources analyzed further in the report. However, it appears that solar PV as well as concentrated solar power (CSP) were implicitly dropped due to their high perceived costs compared to the alternatives. While at first glance the lower LCOE estimates cited in the LCPDP could be within the cost range of candidate projects shown in Table 4, energy planners seem to consider them as unattractive options after the 8% discount rate used throughout the LCPDP (rather than the 5% discount rate used by IEA/NEA and EIA) is applied. The perception of the inadequate economics of solar energy technologies expressed in the LCPDP permeates government policy, as can be seen in various policy documents issued after the publication of the LCPDP (c.f. [34,41]), and this paper therefore serves to test if this view might have to be updated in light of the recent improvements in the economics of solar PV highlighted by Bazilian et al. [7], among others.

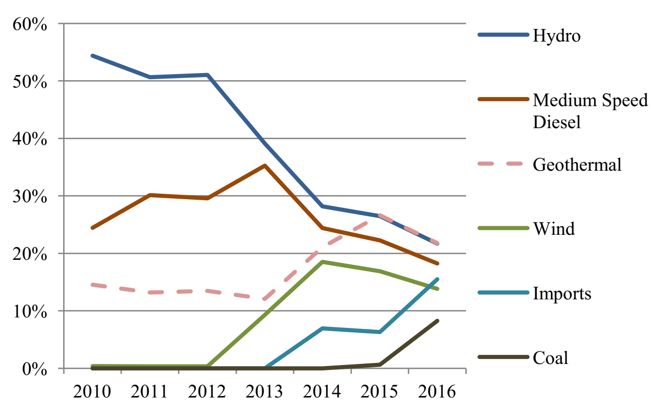

Fig. 2. Share of total installed electricity generation capacity by technology between 2010 and 2016 according to LCPDP 2011–2031 ("base case").
Source: Author's calculation based on [36].

5. Results

In the following sections I present the results of the LCOE modeling undertaken for a hypothetical solar PV plant in Kenya. First, the base case assumptions are documented and results for the base case are shown (Section 5.1). Second, the calculation and analysis of various scenarios and sensitivities is undertaken in Section 5.2, and results are compared to other estimates from the literature in Section 5.3. The discussion of results and possible policy implications follows in Section 6.

5.1. *Cost of solar PV electricity: Base case*

In order to estimate the cost of solar PV electricity in Kenya, the LCOE model described in Section 3.2 was populated with the input values shown in Table 5. Parameter values are based on Kenya-specific sources wherever these were available; in all other cases values are from the relevant literature. The following scenario and sensitivity analysis (see Section 5.2) provides additional information on the reliability and robustness of my results. Table 5 presents the main values used for the calculation of the LCOE of a hypothetical 'utility-scale' solar PV system installed in Kenya by the end of 2011, in that way making the cost of solar electricity broadly comparable with other generation sources considered in the LCPDP 2011–2031.

For the project, a 25-year lifetime is assumed, which is a fairly conservative assumption. The overall system capacity is set at 10 MWp, which marks the upper limit of Kenya's feed-in tariff scheme for renewable energy sources. The overall investment cost is taken from a December 2011 report, for which the authors conducted a survey among solar PV companies to determine the cost of installing a grid-connected solar PV system in Kenya with a capacity of 250 kWp [42]. It should be noted that the installed cost of 2566 USD/kWp falls below other estimates found in the literature, as can be seen in the subsequent scenario analysis. The cost reported by Hille et al. is nevertheless used for the base case since it is assumed that respondents to their survey truthfully reported the actual investment cost at the time the study was conducted. Furthermore, recent reports from Germany, currently the world's largest solar PV market, suggest that this value may still be too high, as prices for household roof-top systems in Germany had fallen to 2080 USD/kWp by June 2012 [44]. Possible economies of scale in the investment cost resulting from the larger assumed system size (10 MWp vs. 250 kWp) are not considered for the base case, but are analyzed as part of the scenario and sensitivity analyses (Section 5.2). The value used for operating costs is in line with the cited literature (see Table 5), and it is further assumed that the project will have a positive scrap value when decommissioned. The value of 10% used here reflects a

Table 5
Main base case input parameters and values for a solar PV system in Kenya.

Input parameter	Value	Unit	Source(s)
Plant lifetime	25	Years	IEA/NEA [9], Peters et al. [19], Schmidt et al. [29]
Installed capacity	10000	kWp	own assumption
Investment cost	2566	USD/kWp	Hille et al. [42]
Operating cost	1.5	Percent	Peters et al. [19], Schmidt et al. [29], Bazilian et al. [7]
Scrap value	10.0	Percent	own assumption
Discount rate (real)	8.0	Percent	Kenya Ministry of Energy [36]
Location	Mombasa	–	own assumption
Global horizontal irradiation	5.43	kWh/m²/day	PVWatts [43]
DC to AC derate factor	76.9	Percent	PVWatts [43]
System output	1374	kWh/kWp	PVWatts [43]
Degradation factor	0.5	Percent	Peters et al. [19]

conservative estimate, i.e. only half the value used, e.g. by [9]. In order to make the solar LCOE comparable with the other technologies analyzed in the LCPDP 2011–2031, the base case uses a discount rate of 8%.

For the base case, it is further assumed that the project is located in a Kenyan location with an average solar irradiance level, such as near Kenya's second largest city, Mombasa. The average GHI in Mombasa is taken as 5.43 kWh/m² per day, based on data from PVWatts, and the resulting electricity yield was also calculated using PVWatts (see Appendix 4 for further information on calculation of the electricity yield). Using the default "DC to AC derate factor" suggested by PVWatts results in a predicted system output of 1374 kWh/kWp per year. In order to ensure this predicted system output is as accurate as possible, I furthermore compared it to the actual performance of Kenya's first grid-connected PV system in Mombasa [45]. This analysis yields an average monthly difference of only 2.5%, suggesting that PVWatts is indeed quite capable of predicting the actual electricity yield. Lastly, to conclude the presentation of the main input values, the annual module degradation is assumed to be 0.5%, in accordance with the cited literature (see Table 5).

Calculation of the LCOE for the hypothetical solar PV plant installed in a location such as Mombasa at the end of 2011 thus yields a cost estimate for solar PV electricity of USD/kWh 0.210 in the base case. This is considerably lower than the values reported in the literature (see Section 2.2) and presumed by Kenyan policymakers (see Section 4.3), and a detailed discussion of this finding follows in Section 6. The calculated plant capacity factor of 15.7% falls within the range reported by Organisation for Economic Co-operation and Development [9], but is somewhat higher than the value given by Schmidt et al. [29], which report it to be 11.3%.

Table 6
LCOE of solar PV electricity in Kenya for different scenario calculations, keeping all other parameters constant at base case values (i.e. 'ceteris paribus').

Scenario parameter/value	Source(s)	USD/kWh
1. Base case		
(as described in Section 5.1 and Table 5)		0.210
2. Plant lifetime (years)		
20	own assumption	0.223
40	Bazilian et al. [7]	0.195
3. Investment cost (USD/kWp)		
2309	own assumption	0.189
3299	Hille et al. [42]	0.270
3594	Solarbuzz [22]	0.294
3667	ECA Ramboll [30]	0.300
4. Operating cost (percent)		
1.0	own assumption	0.200
2.0	Hille et al. [42]	0.220
5. Scrap value (percent)		
0.0	own assumption	0.213
20.0	IEA/NEA [9]	0.207
6. Discount rate (percent)		
5.0	IEA/NEA [9]	0.165
10.0	IEA/NEA [9], Hille et al. [42]	0.242
12.0	Kenya Ministry of Energy [36]	0.275
12.5	Hille et al. [42]	0.284
7. Location (kW h/kWp)		
Nyeri: 1305 (5.04 kWh/m²/day)	PVWatts [43]	0.221
Nairobi: 1344 (5.17 kWh/m²/day)	PVWatts [43]	0.215
Kisumu: 1433 (5.67 kWh/m²/day)	PVWatts [43]	0.202
Lodwar: 1514 (6.15 kWh/m²/day)	PVWatts [43]	0.191
8. Degradation factor (percent)		
0.2	Branker et al. [20]	0.204
1.0	Branker et al. [20]	0.221

5.2. *Cost of solar PV electricity: Scenarios and sensitivities*

In order to test the robustness of the results, a number of scenarios and sensitivities are analyzed in this section. To assess the sensitivity of the results, one parameter is changed at a time, keeping all other parameters constant ('ceteris paribus'). This is followed by a small number of scenarios in which more than one parameter value is changed in order to test the model robustness further. Table 6 presents the scenario parameters that were changed in the first part of the scenario analysis, as well as their specific values in the different scenarios (alongside citations for the values used). It furthermore reports the corresponding LCOE estimates in USD/kWh for every scenario.

As can be seen in the table, neither reducing the project lifetime to 20 years nor increasing it to 40 years has a major influence on the LCOE. Changes in the assumed investment cost, on the other hand, have a major impact on the resulting LCOE. In fact, a 10% decrease or increase in the initial cost leads to an inverse change in the LCOE of similar magnitude, due to the linear function used in the LCOE model. Therefore, the LCOE presented for the base case is highly sensitive to the assumed investment cost. As Table 6 shows, the base case value lies towards the lower range of investment costs reported by Hille et al. [42], Solarbuzz [22] and [34] that were used for the scenario analysis. However, readers should note that these cost estimates are not directly comparable, as none of these studies assumes a utility-scale solar plant of 10 MWp assumed here, which means that their investment costs are not directly applicable but would rather overstate the actual cost that one should expect in this case.

To convert the cost estimates of Hille et al. [42] and other sources from Euros per kWp to USD per kWp, a USD/EUR exchange rate of 1.2219 was used. This is the average exchange rate between the US dollar and Euro from the introduction of the Euro in 2000 until 2011. Using a 10-year or 5-year average instead increases the base case LCOE in dollar terms by 7.4–12.5% (not shown in Table 6). Likewise, increasing or decreasing the operating costs or the scrap value (i.e. negative decommissioning cost) does not change the LCOE much. In contrast, a change in the discount rate significantly impacts on the LCOE, as would be expected with a power plant that is very capital-intensive but has low operating costs. For example, using the lower discount rate of 5% used by Organisation for Economic Co-operation and Development [9] would reduce the LCOE by almost 0.045 USD (or 21%), whereas raising it to the LCPDP's upper value of 12% would result in the LCOE increasing by 0.065 USD (or 31%). This illustrates the particularly high sensitivity to the discount rate applied.

The irradiance-related parameters are of equal importance for the robustness of the results. Based on the meteorological data and technology assumptions underlying PVWatts, the solar electricity yields for four additional locations were calculated: While Nyeri and Lodwar represent the locations with the lowest and highest solar irradiation levels in Kenya, the solar energy potential in Nairobi and Kisumu falls between Nyeri and Mombasa and Mombasa and Lodwar, respectively. Changing the location variable has a significant impact on the LCOE, reducing it by 9.3% in the case of Lodwar and increasing it by 5.3% in the case of Nyeri. However, as the overall variation between locations amounts to only 16%, the absolute range of LCOE values is not unduly large. Additionally, testing different degradation factors does not change the overall result by much.

As presented in Table 6, the scenarios analyzed result in an expected levelized cost of electricity for a utility-scale solar PV plant that ranges from USD/kWh 0.165–0.300. The median value for all 23 scenarios (including the base case) is USD/kWh 0.220, which is very close to the base case LCOE of USD/kWh 0.210, exceeding it by only 4.7%. This suggests that the overall modeling

results are sufficiently robust for deriving a number of policy conclusions. However, in order to test the model's robustness further, the variables with the highest sensitivity were identified. Ordered by the model's sensitivity, the most important variables are (1) the plant location (which determines the level of solar irradiance), (2) the total investment cost, and (3) the discount rate. Identifying the most important variables through the sensitivity analysis allows to further test the scope for deviation from the base case LCOE. For this, four additional scenarios were analyzed, in which a combination of the three most important parameters or, respectively, the entire set of variables contained in Table 6 were changed to their most optimistic and most conservative values (see Table 7).

5.3. Comparison with previous findings

Comparing the base case LCOE of USD/kWh 0.210 as well as the LCOE range resulting from the scenario analysis (USD/kWh 0.165–0.300) with the studies presented in Section 2.1, it can be noted that my results lie significantly below those of previous studies (c.f. Table 2). With the exception of Edenhofer et al. [10] and Johansson et al. [11], which are both recent publications and which both take a global perspective, the other LCOE ranges or point estimates exceed my own estimates by a factor of 2–7. These differences can be attributed to (a) the age of the studies' input values, (b) the global scope of the studies and cost estimates, and (c) the mixing of solar PV as both an on- and an off-grid technology. For instance, all three reasons lie behind the disagreement of my results with those of Collier and Venables [3]: Whereas they base their analysis on outdated cost data, use global cost estimates instead of local (i.e. African) ones and do not differentiate clearly between on- and off-grid solar, my own study explicitly focuses on only one African country and uses inputs that reflect local circumstances. I would argue that this makes my results a more reliable basis for policy decisions, at least in the case of Kenya.

Compared to the 2010 IEA/NEA report (presented in Section 2.2) on which Collier and Venables [3] base their analysis, and the other cost studies presented in Section 2.2, my results suggest an LCOE that is usually lower than the LCOE estimates of studies relying on old data [9,18,19], while generally falling within the LCOE range of the most recent studies (e.g. [7,22,23,24,25,26]). However, more important than a comparison of my results with studies and reports with a global or non-sub-Saharan Africa focus is an evaluation of my LCOE estimates in light of the other studies with an explicit focus on (sub-Saharan) Africa or even Kenya.

This comparison yields the following insights: While the base case LCOE exceeds the estimate of Hauff et al. [27] by USD/kWh 0.035-0.047, it lies markedly below the estimates of Economic Consulting Associates and Ramboll [30], International Renewable Energy Agency [28] and Schmidt et al. [29]. The key reasons for their higher estimates are (a) higher initial cost assumptions and (b) much higher discount rates. In conclusion, my results are thus broadly consistent with the literature, but yield a different LCOE estimates considering that these other studies have used other (and often older) input values. Generally, my LCOE estimate tends to be below the point estimates of comparable studies and readers are free to disagree with any of the inputs used. In order to facilitate their review of my results, this paper transparently presents the values used and gives justifications for their use. Furthermore, the scenario analysis sheds additional light on the robustness of my results, as recommended by Bazilian et al. [7], among others.

6. Discussion

In this paper I analyze whether recent decreases in the cost of solar PV technologies lead to improvements in the economics of solar electricity in Kenya. Furthermore, I investigate whether the claim of Bazilian et al. [7] that policymakers in developing countries are underestimating the potential of solar PV is correct. My results, presented in detail in the preceding section, suggest that the LCOE of solar PV in Kenya is indeed lower than reported in the existing academic and grey literature, which raises a number of important policy implications (Section 6.1). Furthermore, my findings suggest that Kenya's energy planners may be mistaken in presuming that solar energy-based electricity generation cannot contribute to Kenya's power sector expansion in the coming 20 years due to its prohibitive cost. However, readers need to be aware of a number of limitations to my research in order to judge the robustness of my findings appropriately. These caveats are presented in Section 6.2.

6.1. Policy implications: Solar PV in Kenya and beyond

As this paper finds, the *a priori* negative view of energy planners in Kenya is not supported by the facts. Rather, electricity generation from solar energy sources could already be competitive with other power generation technologies in a number of scenarios. As such, Kenyan policymakers may indeed be drawing incorrect conclusions from outdated literature on the cost of solar power, as criticized by Bazilian et al.: “Outdated numbers are still widely disseminated to governments, regulators and investors.” “[And] the impacts of decision-makers not understanding the real costs for PV often has lead to inefficiencies in, inter alia, tariff schemes” ([7], pp. 332 & 336). In addition to a detailed analysis of the actual cost of solar electricity, the dissemination of up-to-date information to Kenya's policymakers is therefore the second aim of this paper.

The LCPDP 2011–2031 assumes that solar energy technologies are not cost-competitive with other generation technologies, as explained in Section 4.3. Despite the lower cost estimates for solar PV reported in this paper, this situation changes only little. At my estimate of USD/kWh 0.210 (and a scenario range of USD/kWh 0.165–0.300), solar PV remains more expensive than any of the other “base load” technologies analyzed in the LCPDP, whose LCOE range from USD/kWh 0.069–0.127 (see Table 4). This suggests that solar PV is indeed not yet competitive when it comes to the provision of base load electricity, which, in the absence of (costly) storage, it would never be able to provide anyhow. Hence, it might be more appropriate to evaluate solar PV as a ‘peak load’ technology, and thus compare it with the candidate peak load technologies also analyzed in the LCPDP. Their costs range from

Table 7
LCOE of solar PV electricity in best and worst case scenarios.

Scenario name	Scenario parameter/value	USD/kWh
“TOP3 best”	Discount rate: 5.0%; investment cost: 2309 USD/kWp; location: Lodwar	0.135
“TOP3 worst”	Discount rate: 12.5%; investment cost: 3667 USD/kWp; location: Nyeri	0.427
“Best case”	All variables set to “best” (i.e. most optimistic) scenario values of Table 6	0.105
“Worst case”	All variables set to “worst” (i.e. most pessimistic) scenario values of Table 6	0.477

USD/kWh 0.151–0.302 according to the LCPDP, a figure largely confirmed by Hille et al. [42]. This implies that solar plants could already produce peak electricity at a cheaper cost than either MSDs or gas turbines running on kerosene.

As described in Section 4.3, Kenya plans to base its future power generation on a mix of technologies and energy sources, many of which will be carbon free and/or based on renewable energy sources. However, past performance and Kenya's medium-term plans suggest that what could actually get built in the next years are MSDs under emergency power agreements, rather than cheaper and cleaner base load technologies [29,46]. Therefore, comparing solar PV with the cost of peak load technologies, such as MSDs, suggests that *actual* power sector expansion could be cheaper if solar power was to replace at least some of the additional fossil fuel plants, a point also made by Hille et al. [42]. Furthermore, the above cost comparison does not consider any external costs associated with the operation of fossil or nuclear power plants. However, such costs, e.g. from local air pollution, greenhouse gas emissions, and nuclear waste disposal, will most certainly add to the cost of conventional power generation, thus improving the competitiveness of solar PV further. Additionally, the long-run marginal cost of Kenya's future generation mix (USD/kWh 0.148) forecast in the LCPDP ([36], p. 118) could be exceeded even without consideration of external costs, should the prices of fossil or nuclear fuels exceed the levels assumed in the LCPDP. Once built, solar PV plants, on the other hand, entail only very low risks of unexpected cost increases, thus lowering the risk of adverse price shocks to electricity consumers. While Hille et al. [42] argue that electricity consumers should use solar energy to generate their own electricity and feed it into the grid through a net-metering mechanism, my results suggest that Kenya's power sector overall could potentially benefit from the introduction of utility-scale solar plants connected to the country's power grid.

Despite the fact that solar PV already appears to be a viable technology option in the circumstances just described, the current regulatory environment for solar PV does not yet allow the adoption of this technology for anything else than the off-grid and mini-grid applications already present in Kenya (Section 4.3). The current feed-in tariff (FIT) for solar PV is set at USD/kWh 0.10–0.20 [47], depending on whether a solar plant's power supply is determined as “firm” or “non-firm”. Yet, even if the regulator were to determine that solar power counts as “firm” (i.e. the plant is deemed able to guarantee the supply of a certain amount of electricity at all times, which may be technically challenging for solar PV plants), and the higher FIT thus applied, would the rate of USD/kWh 0.20 be insufficient to trigger any investments of private investors in grid-connected PV. Raising the FIT for solar PV to an appropriate level would thus be one possible policy measure; ‘net-metering’ for private or small commercial consumers (as suggested by, e.g. [42]) could be another alternative. A third potential measure could be the initiation of a public tender for solar PV electricity, in which project developers would be able to submit offers based on their actual cost of generating solar electricity. Such an approach was taken, for example, by South Africa and illustrates that a tender could arguably facilitate ‘price discovery’ (i.e. how much it really costs to generate solar PV electricity). These policy suggestions, while brief in nature, should be evaluated in further detail in the process of redesigning Kenya's policy instruments for renewable energy sources that is currently being undertaken by the Kenyan MoE and the ERC. While a foregone conclusion of that process appears to be that Kenya should not tap into its solar energy potential on a larger scale (c.f. [30]), my results suggest that facilitating the limited adoption of utility-scale solar PV could enable Kenya to strengthen its position in East Africa's solar energy market (with the economic and employment benefits that this could entail), while at the same time allowing regulators and policymakers to familiarize themselves with a technology whose economic attractiveness is improving rapidly. At the same time, businesses could actively start to exploit the opportunities arising from the changed regulatory environment and engage in the exploitation of Kenya's vast solar resource. How, and to which extent, incumbents and new entrants would do this will depend on many aspects, including the specific regulatory regime.

Beyond Kenya, my findings likewise suggest that solar PV is indeed becoming increasingly attractive as a source of grid-electricity, but that it is probably not yet cost-competitive with the majority of conventional and renewable energy technologies in most locations. However, the view taken by many other researchers in the past years that solar PV in developing countries should ‘forever’ remain limited to off-grid applications, due to its prohibitively high LCOE, most certainly needs to be updated in line with recent cost decreases for the technology. As my research shows, solar PV seems to have reached a cost level where it may already be an attractive alternative to the most expensive conventional generation technologies, such as emergency power plants running on heavy fuel oil (as is the case in Kenya). In contrast to many other renewable energy technologies that may initially exhibit lower generation costs, solar PV furthermore has a number of advantages that may further increase the attractiveness of this technology to policymakers: Unlike geothermal and wind power, for instance, solar PV is rapidly deployable and can be installed incrementally, thus allowing to tailor solar PV installations to when, where and how much electricity is needed. Furthermore, it requires less local infrastructure and technical knowhow for both installation and operation, thus improving reliability and reducing installation and operation costs. Lastly, while not a base load technology, the electricity yield of solar PV plants is generally very predictable, making it a more reliable energy source than, say, wind energy and thus enabling interoperation with existing hydropower plants through “virtual” storage of solar power. Therefore, adding solar PV to the electricity generation mix holds the promise of improving energy security and the reliability of supply, while reducing the burden on the economy and the environment in the long-run through avoided fuel costs, expensive emergency power agreements and emissions.

6.2. Limitations of the results

Readers should note several caveats in interpreting the results presented in Section 5. The biggest among these concerns the appropriateness of the input values used for the calculation of the solar LCOE. The results are highly dependent on a number of input parameters, which, if filled with other values than those applied, will lead to vastly differing results. Therefore, great care was taken in selecting appropriate input values based on a thorough review of the available literature in order to ensure that the model results are as reliable as possible. As explained in Section 5.2, the LCOE model is most sensitive to the assumptions regarding the solar irradiation level, followed by the investment cost and the discount rate, which is in line with the findings of Hille et al. [42] and Organisation for Economic Co-operation and Development et al. [9]. These sensitivities are taken into account in my study as follows. First, the model inputs regarding the expected electricity yields in all five locations investigated can be considered as rather conservative, and the resulting LCOE as an upper bound estimate. Whereas results from RETScreen exceed PVWatts by an average of 6.5%, Hille et al. (ibid) as well as Schmidt et al. [29] assume insolation rates of up to 6.75 kWh/m²/day, which is much higher than even the value assumed for Lodwar (see Section 5.2). Second, the appropriateness of the choice of investment cost in the base case was already documented in detail in Section 5. Third, readers

should note that the base case discount rate of 8% was deliberately chosen in order to align the calculation with Kenya's LCPDP framework. However, this discount rate is most certainly not an appropriate reflection of the cost of capital faced by private investors, which can be expected to be much higher (e.g. [29,42]). Unfortunately, further investigation of this aspect is beyond the scope of this paper.

Further limitations are, first, that in line with common practice the LCOE model does not take into account ‘system costs’, such as the cost of connecting the solar plant to the grid and balancing of the electricity system, which typically incurs higher costs as the share of ‘non-dispatchable’ renewables increases [9]. Second, as a supply-side figure, the LCOE may not fully reflect the ‘true value’ of solar power in a competitive power market, e.g. by shifting the merit order or dispatch curve [7]. Lastly, the LCOE model employed here is a static model in that it does not consider future changes in the cost or efficiency of solar energy technologies, but it seems likely that they would further improve rather than worsen the economics of solar PV in Kenya and the rest of Africa.

6.3. Further research

Lastly, further research appears necessary in a number of areas, which shall be mentioned here briefly. To begin with, more reliable and accurate data on annual solar irradiation levels and their daily and seasonal patterns is urgently needed both for academic research and the actual exploitation of Kenya's (and sub-Saharan Africa's) solar energy resource. Furthermore, present and future costs for investments in solar PV systems and their long-term operation need to be understood better, as do possible economies of scale in installation and operation, in order to improve the accuracy of LCOE calculations. More work is also needed on actual and future costs of conventional technologies, in order to establish an appropriate baseline with which solar energy technologies can be compared. In this comparison, external costs (e.g. for environmental damages) as well as the likelihood of rising (fossil) fuel costs should also be considered in more detail than this paper was able to achieve. Furthermore, additional research should investigate the discount rates actually applied by different types of power plant investors, in order to determine the specific cost of generating solar electricity faced by these investors. These discount rates would need to be reflected in the design of policy instruments and policymakers should recognize that the design of power markets and renewables-related regulation will also have an impact on the perceived risk and hence on the discount rate. Therefore, these two aspects should also be analyzed further. Lastly, academics and policymakers throughout developing countries ought to look into the potential of using other solar electricity technologies beyond solar PV. Both CSP and concentrated photovoltaics (CPV) hold the potential of combining low generation costs with stable, and in the case of CSP even base load, power generation, potentially making them even more suitable for dry African locations near the equator than solar PV.

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Appendix A. Supplementary material

Supplementary data and information associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.rser.2013.10.010.

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